STATE OF IDAHO
DEPARTMENT OF
ENVIRONMENTAL QUALITY

1410 North Hilton • Boise, Idaho 83706 • (208) 373-0502
www.deq.idaho.gov

Governor Brad Little
Director John H. Tippets

October 2, 2019

Sam Merrick, HVAC Services Manager
Brigham Young University Idaho
525 S. Center St.
Rexburg, ID 83460

RE: Facility ID No. 065-00011, Brigham Young University Idaho, Rexburg
Final Permit Letter

Dear Mr. Merrick:

The Department of Environmental Quality (DEQ) is issuing Permit to Construct (PTC) No. P-2013.0057 Project 62292 to Brigham Young University Idaho located at Rexburg for the removal of five emergency IC engines powering electrical generators. This PTC is issued in accordance with IDAPA 58.01.01.200 through 228 (Rules for the Control of Air Pollution in Idaho) and is based on the certified information provided in your PTC application received August 26, 2019.

This permit is effective immediately and replaces PTC No. P-2013.0057, issued on November 18, 2016. This permit does not release Brigham Young University Idaho from compliance with all other applicable federal, state, or local laws, regulations, permits, or ordinances.

Pursuant to the Construction and Operation Notification General Provision of your permit, it is required that construction and operation notification be provided. Please provide this information as listed to DEQ's Idaho Falls Regional Office, 900 N. Skyline, Ste. B, Idaho Falls, ID 83402, Fax (208) 528-2695.

In order to fully understand the compliance requirements of this permit, DEQ highly recommends that you schedule a permit handoff meeting with Rensay Owen, Regional Air Quality Manager, at (208) 528-2650 to review and discuss the terms and conditions of this permit. Should you choose to schedule this meeting, DEQ recommends that the following representatives attend the meeting: your facility's plant manager, responsible official, environmental contact, and any other staff responsible for day-to-day compliance with permit conditions.

Pursuant to IDAPA 58.01.23, you, as well as any other entity, may have the right to appeal this final agency action within 35 days of the date of this decision. However, prior to filing a petition for a contested case, I encourage you to contact Kelli Wetzel at (208) 373-0502 or kelli.wetzel@deq.idaho.gov to address any questions or concerns you may have with the enclosed permit.

Sincerely,

Mike Simon
Stationary Source Program Manager
Air Quality Division

MS\kw

Permit No. P-2013.0057 PROJ 62292

Air Quality

PERMIT TO CONSTRUCT

Permittee	Brigham Young University Idaho
Permit Number	P-2013.0057
Project ID	62292
Facility ID	065-00011
Facility Location	525 S. Center St. Rexburg, ID 83460

Permit Authority

This permit (a) is issued according to the "Rules for the Control of Air Pollution in Idaho" (Rules), IDAPA 58.01.01.200–228; (b) pertains only to emissions of air contaminants regulated by the State of Idaho and to the sources specifically allowed to be constructed or modified by this permit; (c) has been granted on the basis of design information presented with the application; (d) does not affect the title of the premises upon which the equipment is to be located; (e) does not release the permittee from any liability for any loss due to damage to person or property caused by, resulting from, or arising out of the design, installation, maintenance, or operation of the proposed equipment; (f) does not release the permittee from compliance with other applicable federal, state, tribal, or local laws, regulations, or ordinances; and (g) in no manner implies or suggests that the Idaho Department of Environmental Quality (DEQ) or its officers, agents, or employees assume any liability, directly or indirectly, for any loss due to damage to person or property caused by, resulting from, or arising out of design, installation, maintenance, or operation of the proposed equipment. Changes in design, equipment, or operations may be considered a modification subject to DEQ review in accordance with IDAPA 58.01.01.200–228.

Date Issued October 2, 2019

Kelli Wetzel

Kelli Wetzel, Permit Writer

Mike Simon, Stationary Source Manager

Contents

1 Permit Scope

Purpose

1.1 This is a revised permit to construct (PTC) to remove five emergency IC engines powering electric generators. The five emergency IC engines are Engine 40014 in the Austin Tech Building, Engine 40004 in the Romney Building, Engine 40031 in the McKay Library, Engine 40013 in the Benson Building, and Engine 40020 in the Smith Building.

1.2 Those permit conditions that have been modified or revised by this permitting action are identified by the permit issue date citation located directly under the permit condition and on the right-hand margin.

1.3 This PTC replaces Permit to Construct No. P-2013.0057, issued on November 18, 2016.

Regulated Sources

Table 1.1 lists all sources of regulated emissions in this permit.

Table 1.1 Regulated Sources

Permit Section	Source	Control Equipment
2	Boiler No. 2: Manufacturer: Cleaver Brooks Model: Type "O" Burner Mfg.: Natcom Burner Model: NOS-2-54 Installation Date: 2014 Heat input rating: 55.0 MMBtu/hr Primary Fuel: Natural gas Backup Fuel: ULSD fuel	N/A
	Boiler No. 3: Manufacturer: Cleaver Brooks Model: Type "O" Burner Mfg.: Natcom Burner Model: NOS-2-54 Installation Date: 2014 Heat input rating: 55.0 MMBtu/hr Primary Fuel: Natural gas Backup Fuel: ULSD fuel	N/A
	Boiler No. 4: Manufacturer: Cleaver-Brooks Model: Type CBEX Elite Burner Mfg.: Cleaver-Brooks Burner Model: CBEX Elite Installation Date: 2014 Heat input rating: 25.682 MMBtu/hr Primary Fuel: Natural gas Backup Fuel: ULSD fuel	N/A
3	Combustion Turbine: Manufacturer: Solar Turbine Model: Taurus 60-7901S Manufacture Date: 2013 Heat input rating: 60 MMBtu/hr Primary Fuel: Natural gas Backup Fuel: ULSD fuel	N/A

Permit Section	Source	Control Equipment
3	Duct Burner: Manufacturer: Natcom Burner Model: MF-4(S)-70 HRSG Manufacture Date: 2013 Heat input rating: 30 MMBtu/hr Fuel: Natural gas only	N/A
4	Emergency IC Engine 40084, Central Energy Plant: Manufacturer: Volvo Model: TAD1641GE Manufacture Date: 2013 Max. rating: 757 bhp Tier rating: Tier 2 Fuel: ULSD only	N/A
	Emergency IC Engine 40085, Central Energy Plant: Manufacturer: Volvo Model: TAD1641GE Manufacture Date: 2013 Max. rating: 757 bhp Tier rating: Tier 2 Fuel: ULSD only	N/A
	Emergency Generator No. 40002: Caterpillar Model SR4B Diesel-fired, 438 kW, located at Kimball Building, installed before 2004	N/A
	Emergency Generator No. 40077: Generac Model 2570000000 Diesel-fired, 100 kW, located at Hart Building, installed before 2004	N/A
	Emergency Generator No. 40082: Generac Model 9900000000 Diesel-fired, 500 kW, located outside the Heat Plant, installed 2008	N/A
	Emergency Generator No. 40083: Generac Model 9900000000 Diesel-fired, 500 kW, located outside the Heat Plant, installed 2008	N/A
	Emergency Generator No. 40010: Onan Model DGBB5007082 Diesel-fired, 35 kW, located at Spori/Kirkham Building, installed before 2004	N/A
	Emergency Generator No. 40080: Olympian Model 94A03525-S Diesel-fired, 60 kW, located at Auxiliary Services, installed before 2004	N/A
	Emergency Generator No. 40016: Generac Model 5690000000 Diesel-fired, 80 kW, located in Snow Performing Arts Center, installed 2006	N/A
	Emergency Generator No. 40015: Generac Model 5170000000 Diesel-fired, 60 kW, located at Clark Building, installed 2005	N/A
	Emergency Generator No. 40009: Generac Model 20A02581-S Diesel-fired, 40 kW, located at KRIC, installed before 2004	N/A

Permit Section	Source	Control Equipment
4	Emergency Generator No. 40012: Generac Model 3430000000 Diesel-fired, 80 kW, located at Ricks/Hinckley Building, installed before 2004	N/A
	Emergency Generator No. 40008: Onan Model 5DNAA Diesel-fired, 50 kW, located at Radio Tower, installed before 2004	N/A
	Emergency Generator No. 40011: Cummins Model DGGD5632344 Diesel-fired, 35 kW, located at the Substation, installed before 2004	N/A
	Emergency Generator No. 40018: Generac Model 6950000000 Diesel-fired, 130 kW, located at Menan Butte, installed 2006	N/A
5	Physical Facilities #1 Spray Booth: Graco Model 220955 Airless spray gun, 5 gal/hr capacity	Pre-filter and filter system Airless spray gun
	Physical Facilities #2 Spray Booth: Graco Model 395 Airless spray gun, 5 gal/hr capacity	Pre-filter and filter system Airless spray gun
	Austin Spray Booth: Campbell Housefield HVLP spray gun, 1.5 gal/hr capacity	Pre-filter and filter system HVLP spray gun

[10/2/2019]

2 Boilers No. 2, No. 3, and No. 4

2.1 Process Description

The central heating plant boilers provide a continuous flow of steam through buried steam lines to all of the major buildings on campus. The primary purpose of the boilers is to generate steam for space heating on campus, but steam is also used for some sidewalk snow melting, steam kettle cooking in the Student Center kitchen, building humidification, domestic water and swimming pool heating, and autoclave sterilization in the Health Unit.

2.2 Control Device Descriptions

Table 2.1 Boilers No. 2, No. 3, and No. 4 Description

Emissions Units / Processes	Control Devices	Emission Points
Boiler No. 2	N/A	Boiler No. 2 exhaust
Boiler No. 3	N/A	Boiler No. 3 exhaust
Boiler No. 4	N/A	Boiler No. 4 exhaust

[11/6/2014]

Emission Limits

2.3 Emission Limits

The emissions from the Boilers No. 2, No. 3, and No. 4 stacks shall not exceed any corresponding emissions rate limits listed in Table 2.2.

Table 2.2 Boilers No. 2, No. 3, and No. 4 Emission Limits (a)

Source Description	PM_{10} (b)		SO_2		NO_X		CO		VOC	
	lb/hr (c)	T/yr (d)	lb/hr (c)	T/yr (d)	lb/hr (c)(e)	T/yr (d)(f)	lb/hr (c)	T/yr (d)	lb/hr (c)	T/yr (d)
Boiler No. 2	2.48	2.02	0.09	0.11	7.91	8.71	3.23	8.52	0.33	0.81
Boiler No. 3	2.48	2.02	0.09	0.11	7.91	8.71	3.23	8.52	0.33	0.81
Boiler No. 4	0.60	0.50	0.04	0.04	2.93	2.36	3.00	7.34	0.16	0.39

a) In absence of any other credible evidence, compliance is ensured by complying with permit operating, monitoring, and record keeping requirements.
b) Particulate matter with an aerodynamic diameter less than or equal to a nominal ten (10) micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.
c) Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference test method, continuous emission monitoring system (CEMS) data, or DEQ-approved alternative.
d) Tons per any consecutive 12-calendar month period.
e) Hourly NO_X emissions are based on the worst-case scenario when combusting ULSD as fuel.
f) Annual NO_X emissions are based on combusting natural gas with ULSD as backup.

[11/18/2016]

2.4 Opacity Limit

Emissions from the Boilers No. 2, No. 3, and No. 4 stacks, or any other stack, vent, or functionally equivalent opening associated with Boilers No. 2, No. 3, and No. 4, shall not exceed 20% opacity for a period or periods aggregating more than three minutes in any 60-minute period as required by IDAPA 58.01.01.625. Opacity shall be determined by the procedures contained in IDAPA 58.01.01.625.

2.5 Grain Loading

The permittee shall not discharge to the atmosphere from any fuel-burning equipment PM in excess of 0.015 grains per dry standard cubic foot (gr/dscf) of effluent gas corrected to 3% oxygen by volume for gaseous fuels and 0.050 gr/dscf of effluent gas corrected to 3% oxygen by volume for liquid fuels.

Operating Requirements

2.6 Primary and Backup Fuel Use

Boilers No. 2, No. 3, and No. 4 shall primarily combust natural gas as fuel. Boilers No. 2, No. 3, and No. 4 may combust ultra-low sulfur diesel (ULSD) fuel as backup during a natural gas curtailment, for testing purposes, or for fuel oil rotation.

[11/6/2014]

2.7 Boilers No. 2, No. 3, and No. 4 Operating Limits

To demonstrate compliance with the Emissions Limits permit condition operation of Boilers No. 2, No. 3, and No. 4 shall not exceed the following operational limits:

- 744.2 MMscf (for all three boilers combined) per any consecutive 12-month period when combusting natural gas as fuel
- 48 hours (per each boiler) per any consecutive 12-month period when combusting ULSD as fuel for testing purposes or fuel oil rotation.

[11/18/2016]

Operating Requirements

2.8 Ultra-Low Sulfur Diesel (ULSD) Fuel Specifications

ULSD fuel oil is fuel which meets ASTM Grades 1 or 2, or a mixture of ASTM Grades 1 and 2, and which has a maximum sulfur content of 0.0015% (15 ppm) by weight.

[11/6/2014]

Monitoring and Recordkeeping Requirements

2.9 Fuel Specifications Recordkeeping

On an as-received basis for each shipment of distillate fuel oil for the boilers, the permittee shall maintain the following supplier verified and certified information:

- Percent sulfur content by weight.

[11/6/2014]

2.10 Boilers No. 2, No. 3, and No. 4 Operation Recordkeeping

The permittee shall monitor and record Boilers No. 2, No. 3, and No.4 operation in hours per day and the fuel being used to demonstrate compliance with the Boilers No. 2, No. 3, and No. 4 Operating Limits permit condition. Monthly operation of Boilers No. 2, No. 3, and No. 4 shall be determined by summing daily operation over the previous calendar month. Consecutive 12-months operation of Boilers No. 2, No. 3, and No. 4 shall be determined by summing the monthly operation over the previous consecutive 12 month period to demonstrate compliance with the consecutive 12-months Boilers No. 2, No. 3, and No. 4 Operating Limits permit condition.

[11/6/2014]

40 CFR 60, Subpart Dc Requirements

2.11 Standards for Sulfur Dioxide (SO_2)

In accordance with 40 CFR 60.42c (h) and (i), for affected facilities listed under paragraphs (h)(1), (2), (3), or (4) of this section, compliance with the emission limits or fuel oil sulfur limits under this section may be determined based on a certification from the fuel supplier, as described under §60.48c(f), as applicable.

- Distillate oil-fired affected facilities with heat input capacities between 2.9 and 29 MW (10 and 100 MMBtu/hr).

The SO_2 emission limits, fuel oil sulfur limits, and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

[11/6/2014]

2.12 Standards for Particulate Matter (PM)

In accordance with 40 CFR 60.43c (c) and (d), on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, wood, or oil and has a heat input capacity of 8.7 MW (30 MMBtu/h) or greater shall cause to be discharged into the atmosphere from that affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators of an affected facility that elect to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and are subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less are exempt from the opacity standard specified in this paragraph (c). The PM and opacity standards under this section apply at all times, except during periods of startup, shutdown, or malfunction.

[11/6/2014]

2.13 Compliance and Performance Test Methods and Procedures for Sulfur Dioxide

In accordance with 40 CFR 60.44c (h), for affected facilities subject to §60.42c(h)(1), (2), or (3) where the owner or operator seeks to demonstrate compliance with the SO_2 standards based on fuel supplier certification, the performance test shall consist of the certification from the fuel supplier, as described in §60.48c(f), as applicable.

[11/6/2014]

2.14 Emissions Monitoring for Particulate Matter

In accordance with 40 CFR 60.47c (a), the owner or operator of an affected facility subject to an opacity standard in §60.43c(c) that is not required to use a COMS due to paragraphs (c), (d), (e), or (f) of this section that elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in §60.11 to demonstrate compliance with the applicable limit in §60.43c by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility (when combusting fuel oil), whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

[11/6/2014]

2.15 Emissions Monitoring for Particulate Matter

In accordance with 40 CFR 60.47c (a)(1), (2), and (3), except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

- If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;
- If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;
- If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or
- If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

- The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (i.e., 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (i.e., 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (i.e., 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in §60.45c(a)(8).
- If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

[11/6/2014]

2.16 Emissions Monitoring for Particulate Matter

In accordance with 40 CFR 60.47c (c), owners and operators of an affected facilities that burn only distillate oil that contains no more than 0.5 weight percent sulfur and/or liquid or gaseous fuels with potential sulfur dioxide emission rates of 26 ng/J (0.060 lb/MMBtu) heat input or less and that do not use a post-combustion technology to reduce SO_2 or PM emissions and that are subject to an opacity standard in §60.43c(c) are not required to operate a COMS if they follow the applicable procedures in §60.48c(f).

[11/6/2014]

2.17 Emissions Monitoring for Particulate Matter

In accordance with 40 CFR 60.47c (f)(3), an owner or operator of an affected facility that is subject to an opacity standard in §60.43c(c) is not required to operate a COMS provided that the affected facility meets the conditions in either paragraphs (f)(1), (2), or (3) of this section. The affected facility burns only gaseous fuels and/or fuel oils that contain no greater than 0.5 weight percent sulfur, and the owner or operator operates the unit according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under §60.48c(c).

[11/6/2014]

2.18 Reporting and Recordkeeping Requirements

In accordance with 40 CFR 60.48c (a), the owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by §60.7 of this part. This notification shall include:

- The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.
- If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42c, or §60.43c.
- The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

- Notification if an emerging technology will be used for controlling SO2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

[11/6/2014]

2.19 Reporting and Recordkeeping Requirements

In accordance with 40 CFR 60.48c (d), the owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall submit reports to the Administrator.

[11/6/2014]

2.20 Reporting and Recordkeeping Requirements

In accordance with 40 CFR 60.48c (e), the owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

- Calendar dates covered in the reporting period.
- Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.
- Each 30-day average percent of potential SO_2 emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.
- Identification of any steam generating unit operating days for which SO_2 or diluent (O_2 or CO_2) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and a description of corrective actions taken.
- Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.
- Identification of the F factor used in calculations, method of determination, and type of fuel combusted.
- If fuel supplier certification is used to demonstrate compliance, records of fuel supplier certification as described under paragraph (f)(1), (2), (3), or (4) of this section, as applicable. In addition to records of fuel supplier certifications, the report shall include a certified statement signed by the owner or operator of the affected facility that the records of fuel supplier certifications submitted represent all of the fuel combusted during the reporting period.

[11/6/2014]

2.21 Reporting and Recordkeeping Requirements – Fuel Supplier Certification

In accordance with 40 CFR 60.48c (f), Fuel supplier certification shall include the following information:

For distillate oil:

- The name of the oil supplier;
- A statement from the oil supplier that the oil complies with the specifications under the definition of distillate oil in §60.41c; and
- The sulfur content or maximum sulfur content of the oil.

[11/6/2014]

2.22 Reporting and Recordkeeping Requirements – Fuel records

In accordance with 40 CFR 60.48c (g), except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

- As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.
- As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the SO_2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

[11/6/2014]

2.23 Reporting and Recordkeeping Requirements – Annual Capacity Factor

In accordance with 40 CFR 60.48c (h), the owner or operator of each affected facility subject to a federally enforceable requirement limiting the annual capacity factor for any fuel or mixture of fuels under §60.42c or §60.43c shall calculate the annual capacity factor individually for each fuel combusted. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of the calendar month.

[11/6/2014]

2.24 Reporting and Recordkeeping Requirements

In accordance with 40 CFR 60.48c (i), all records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

[11/6/2014]

2.25 Reporting and Recordkeeping Requirements

In accordance with 40 CFR 60.48c (j), the reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

[11/6/2014]

2.26 Boilers No. 2, No. 3, and No. 4 Notification Address

In accordance with 40 CFR 60.7, any notifications or reporting required by the Standards of Performance of New Stationary Sources (NSPS), 40 CFR Part 60, Subpart Dc or Subpart A – General Provisions shall be submitted to the following address:

Air Quality Permit Compliance
Idaho Falls Regional Office
Department of Environmental Quality
900 N. Skyline, Ste. B
Idaho Falls, ID 83402

Phone: (208) 528-2650
Fax: (208) 528-2695

[10/2/2019]

2.27 Incorporation of Federal Requirements by Reference

Unless expressly provided otherwise, any reference in this permit to any document identified in IDAPA 58.01.01.107.03 shall constitute the full incorporation into this permit of that document for the purposes of the reference, including any notes and appendices therein. Documents include, but are not limited to:

- New Source Performance Standards (NSPS), 40 CFR Part 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

For permit conditions referencing or cited in accordance with any document incorporated by reference (including permit conditions identified as NSPS), should there be any conflict between the requirements of the permit condition and the requirements of the document, the requirements of the document shall govern, including any amendments to that regulation.

[11/6/2014]

3 Combustion Turbine and Duct Burner

3.1 Process Description

The BYU Idaho power plant will operate as a one-on-one, combined-cycle plant, consisting of a natural gas-fired combustion turbine (CT). The CT is equipped with a heat recovery steam generator (HRSG) which uses the exhaust heat to produce steam. A natural gas-fired duct burner within the HRSG provides additional heat in the exhaust gases, which increases steam production for peak loads.

3.2 Control Device Descriptions

Table 3.1 Combustion Turbine and Dust Burner Description

Emissions Units / Processes	Control Devices	Emission Points
Combustion Turbine:	N/A	Combustion Turbine Exhaust Stack and Duct Burner Bypass Stack
Duct Burner:	N/A	

[11/6/2014]

Emission Limits

3.3 Emission Limits

The emissions from the Combustion Turbine and Duct Burner stack shall not exceed any corresponding emissions rate limits listed in Table 3.2.

Table 3.2 Combustion Turbine and Duct Burner Emission Limits [(a)]

Source Description	PM_{10} (b)		SO_2		NO_X		CO		VOC	
	lb/hr (c)	T/yr (d)	lb/hr (c)	T/yr (d)	lb/hr (c)(e)	T/yr (d)(f)	lb/hr (c)	T/yr (d)	lb/hr (c)	T/yr (d)
Combustion Turbine	0.72	1.80	0.09	0.04	24.12	29.90	5.49	24.08	0.13	0.54
Duct Burner	0.41	0.99	0.02	0.05	4.22	10.33	4.22	10.33	0.18	0.45

a) In absence of any other credible evidence, compliance is ensured by complying with permit operating, monitoring, and record keeping requirements.
b) Particulate matter with an aerodynamic diameter less than or equal to a nominal ten (10) micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.
c) Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference test method, continuous emission monitoring system (CEMS) data, or DEQ-approved alternative.
d) Tons per any consecutive 12-calendar month period.
e) Hourly NO_X emissions are based on the worst-case scenario when combusting ULSD as fuel.
f) Annual NO_X emissions are based on combusting natural gas with ULSD as backup.

[11/18/2016]

3.4 Opacity Limit

Emissions from the Combustion Turbine and Duct Burner stack, or any other stack, vent, or functionally equivalent opening associated with the Combustion Turbine and Duct Burner, shall not exceed 20% opacity for a period or periods aggregating more than three minutes in any 60-minute period as required by IDAPA 58.01.01.625. Opacity shall be determined by the procedures contained in IDAPA 58.01.01.625.

3.5 Grain Loading

The permittee shall not discharge to the atmosphere from any fuel-burning equipment PM in excess of 0.015 grains per dry standard cubic foot (gr/dscf) of effluent gas corrected to 3% oxygen by volume for gaseous fuels and 0.050 gr/dscf of effluent gas corrected to 3% oxygen by volume for liquid fuels.

[11/6/2014]

Operating Requirements

3.6 Combustion Turbine Primary and Backup Fuel Use

The Combustion Turbine shall primarily combust natural gas as fuel. The Combustion Turbine may combust ULSD fuel as backup during a natural gas curtailment or for testing purposes.

[11/6/2014]

3.7 Combustion Turbine Operating Limit

To demonstrate compliance with the Emissions Limits permit condition operation of the Combustion Turbine shall not exceed the following operational limit:

- 400 hours per any consecutive 12-month period when combusting ULSD as fuel

[11/6/2014]

Fuel Specifications

3.8 ULSD Fuel Specifications

ULSD fuel oil is fuel which meets ASTM Grades 1 or 2, or a mixture of ASTM Grades 1 and 2, and which has a maximum sulfur content of 0.0015% (15 ppm) by weight.

[11/6/2014]

Monitoring and Recordkeeping Requirements

3.9 Combustion Turbine Operation Recordkeeping

When combusting ULSD fuel oil the permittee shall monitor and record the Combustion Turbine operation in hours per day to demonstrate compliance with the Combustion Turbine Operating Limit permit condition.

Monthly operation of the Combustion Turbine shall be determined by summing daily operation over the previous calendar month. Consecutive 12-months operation of the Combustion Turbine shall be determined by summing the monthly operation over the previous consecutive 12 month period to demonstrate compliance with the consecutive 12-months Combustion Turbine Operating Limit permit condition.

[11/6/2014]

3.10 Fuel Specifications Recordkeeping

On an as-received basis for each shipment of distillate fuel oil for the Combustion Turbine, the permittee shall maintain the following supplier verified and certified information:

- Percent sulfur content by weight.

[11/6/2014]

40 CFR 60, Subpart KKKK Requirements

3.11 What emission limits must I meet for NO_X if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?

In accordance with 40 CFR 60.4320 and 4325, the owner or operator must meet the emission limits specified in Table 1 to this subpart. If your total heat input is greater than or equal to 50 percent natural gas, you must meet the corresponding limit for a natural gas-fired turbine when you are burning that fuel. Similarly, when your total heat input is greater than 50 percent distillate oil and fuels other than natural gas, you must meet the corresponding limit for distillate oil and fuels other than natural gas for the duration of the time that you burn that particular fuel.

Table 3.3 Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New turbine firing natural gas	> 50 MMBtu/hr and ≤ 850 MMBtu/hr	25 ppm at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O_2 or 460 ng/J of useful output (3.6 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O_2 or 110 ng/J of useful output (0.86 lb/MWh).

[11/18/2016]

3.12 What emission limits must I meet for sulfur dioxide (SO_2)?

In accordance with 40 CFR 60.4330 (a), if your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section as listed below.

- You must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output;
- You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement.

[11/6/2014]

3.13 What are my general requirements for complying with this subpart?

In accordance with 40 CFR 60.4333 (a), you must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

[11/6/2014]

3.14 How do I demonstrate continuous compliance for NO_X if I do not use water or steam injection?

In accordance with 40 CFR 60.4340 (a) and (b), if you are not using water or steam injection to control NO_X emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_X emission limit for the turbine, you must resume annual performance tests.

As an alternative to the NO_X testing in the preceding paragraph, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

- Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or
- Continuous parameter monitoring as follows:
    - For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO_X formation characteristics, and you must monitor these parameters continuously.
    - For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode.
    - For any turbine that uses SCR to reduce NO_X emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.
    - For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in §75.19(c)(1)(iv)(H).

[11/6/2014]

3.15 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?

In accordance with 40 CFR 60.4345 (a), (b), (c), (d), and (e), each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to appendix A of part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

As specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

Each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter.

[11/6/2014]

3.16 How do I use data from the continuous emission monitoring equipment to identify excess emissions?

In accordance with 40 CFR 60.4350 (a), (b), (c), (d), (e), (f), (g), and (h), for purposes of identifying excess emissions:

All CEMS data must be reduced to hourly averages as specified in §60.13(h).

For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the following equation for units complying with the output based standard:

For simple-cycle operation:

$$E = \frac{(NO_X)_h * (HI)_h}{P} \quad \text{(Eq. 1)}$$

Where:

E = hourly NO_X emission rate, in lb/MWh,

$(NO_X)_h$ = hourly NO_X emission rate, in lb/MMBtu,

$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flowmeter(s), e.g., calculated using Equation D-15a in appendix D to part 75 of this chapter, and

P = gross energy output of the combustion turbine in MW.

For combined-cycle and combined heat and power complying with the output-based standard, use Equation 1 of this subpart, except that the gross energy output is calculated as the sum of the total electrical and mechanical energy generated by the combustion turbine, the additional electrical or mechanical energy (if any) generated by the steam turbine following the heat recovery steam generator, and 100 percent of the total useful thermal energy output that is not used to generate additional electricity or mechanical output, expressed in equivalent MW, as in the following equations:

$$P = (Pe)t + (Pe)c + Ps + Po \quad \text{(Eq. 2)}$$

Where:

P = gross energy output of the stationary combustion turbine system in MW.

(Pe)t = electrical or mechanical energy output of the combustion turbine in MW,

(Pe)c = electrical or mechanical energy output (if any) of the steam turbine in MW, and

$$P_S = \frac{Q * H}{3.413 \times 10^6 \, \text{Btu/MWh}} \quad \text{(Eq. 3)}$$

Where:

Ps = useful thermal energy of the steam, measured relative to ISO conditions, not used to generate additional electric or mechanical output, in MW,

Q = measured steam flow rate in lb/h,

H = enthalpy of the steam at measured temperature and pressure relative to ISO conditions, in Btu/lb, and 3.413×10^6 = conversion from Btu/h to MW.

Po = other useful heat recovery, measured relative to ISO conditions, not used for steam generation or performance enhancement of the combustion turbine.

For mechanical drive applications complying with the output-based standard, use the following equation:

$$E = \frac{(NO_X)_m}{(BL * AL)} \quad \text{Eq. 4}$$

Where:

E = NO_X emission rate in lb/MWh,

$(NO_X)_m$ = NOX emission rate in lb/h,

BL = manufacturer's base load rating of turbine, in MW, and

AL = actual load as a percentage of the base load.

For simple cycle units without heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 4-hour rolling average basis, as described in §60.4380(b)(1).

For combined cycle and combined heat and power units with heat recovery, use the calculated hourly average emission rates from paragraph (f) of this section to assess excess emissions on a 30 unit operating day rolling average basis, as described in §60.4380(b)(1).

[11/6/2014]

3.17 How do I establish and document a proper parameter monitoring plan?

In accordance with 40 CFR 60.4355 (a) and (b), the steam or water to fuel ratio or other parameters that are continuously monitored as described in §§60.4335 and 60.4340 must be monitored during the performance test required under §60.8, to establish acceptable values and ranges. You may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. You must develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan must:

- Include the indicators to be monitored and show there is a significant relationship to emissions and proper operation of the NOX emission controls,
- Pick ranges (or designated conditions) of the indicators, or describe the process by which such range (or designated condition) will be established,
- Explain the process you will use to make certain that you obtain data that are representative of the emissions or parameters being monitored (such as detector location, installation specification if applicable),
- Describe quality assurance and control practices that are adequate to ensure the continuing validity of the data,
- Describe the frequency of monitoring and the data collection procedures which you will use (e.g., you are using a computerized data acquisition over a number of discrete data points with the average (or maximum value) being used for purposes of determining whether an exceedance has occurred), and
- Submit justification for the proposed elements of the monitoring. If a proposed performance specification differs from manufacturer recommendation, you must explain the reasons for the differences. You must submit the data supporting the justification, but you may refer to generally available sources of information used to support the justification. You may rely on engineering assessments and other data, provided you demonstrate factors which assure compliance or explain why performance testing is unnecessary to establish indicator ranges. When establishing indicator ranges, you may choose to simplify the process by treating the parameters as if they were correlated. Using this assumption, testing can be divided into two cases:
    - All indicators are significant only on one end of range (e.g., for a thermal incinerator controlling volatile organic compounds (VOC) it is only important to insure a minimum temperature, not a maximum). In this case, you may conduct your study so that each parameter is at the significant limit of its range while you conduct your emissions testing. If the emissions tests show that the source is in compliance at the significant limit of each parameter, then as long as each parameter is within its limit, you are presumed to be in compliance.
    - Some or all indicators are significant on both ends of the range. In this case, you may conduct your study so that each parameter that is significant at both ends of its range assumes its extreme values in all possible combinations of the extreme values (either single or double) of all of the other parameters. For example, if there were only two parameters, A and B, and A had a range of values while B had only a minimum value, the combinations would be A high with B minimum and A low with B minimum. If both A and B had a range, the combinations would be A high and B high, A low and B low, A high and B low, A low and B high. For the case of four parameters all having a range, there are 16 possible combinations.

For affected units that are also subject to part 75 of this chapter and that have state approval to use the low mass emissions methodology in §75.19 or the NO_X emission measurement methodology in appendix E to part 75, you may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a QA plan, as described in §75.19(e)(5) or in section 2.3 of appendix E to part 75 of this chapter and section 1.3.6 of appendix B to part 75 of this chapter.

[11/6/2014]

3.18 How can I be exempted from monitoring the total sulfur content of the fuel?

In accordance with 40 CFR 60.4365 (a), the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas.

[11/6/2014]

3.19 What reports must I submit?

In accordance with 40 CFR 60.4375 (a) and (b), for each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

For each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

[11/6/2014]

3.20 How are excess emissions and monitor downtime defined for NO_X?

In accordance with 40 CFR 60.4380 (a) and (b), for the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

For turbines using water or steam to fuel ratio monitoring:

- An excess emission is any unit operating hour for which the 4-hour rolling average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.4320, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine when a fuel is being burned that requires water or steam injection for NO_X control will also be considered an excess emission.
- A period of monitor downtime is any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.
- Each report must include the average steam or water to fuel ratio, average fuel consumption, and the combustion turbine load during each excess emission.

For turbines using continuous emission monitoring, as described in §§60.4335(b) and 60.4345:

- An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.
- A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO_2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.
- For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

[11/6/2014]

3.21 How do I conduct the initial and subsequent performance tests, regarding NO_X?

In accordance with 40 CFR 60.4400 (a) and (b), you must conduct an initial performance test, as required in §60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

There are two general methodologies that you may use to conduct the performance tests. For each test run:

1) Measure the NO_X concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate:

$$E = \frac{1.194\times10^{-7} * (NO_X)_c * Q_{std}}{P} \quad \text{Eq. 5}$$

Where:

E = NO_X emission rate, in lb/MWh

1.194×10^{-7} = conversion constant, in lb/dscf-ppm

$(NO_X)_c$ = average NO_X concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2);

or

2) Measure the NO_X and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the NO_X emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NO_X emission rate in lb/MWh.

Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

Notwithstanding paragraph (a)(2) of this section (the preceding paragraph), you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

- You may perform a stratification test for NO_X and diluent pursuant to the procedures specified in section 6.5.6.1(a) through (e) of appendix A of part 75 of this chapter.
- Once the stratification sampling is completed, you may use the following alternative sample point selection criteria for the performance test:
  - If each of the individual traverse point NO_X concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then you may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or
  - For turbines with a NO_X standard greater than 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO_2 (or O_2) from the mean for all traverse points; or

- For turbines with a NO_X standard less than or equal to 15 ppm @ 15% O_2, you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.

The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

- If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel.
- For a combined cycle and CHP turbine systems with supplemental heat (duct burner), you must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.
- Compliance with the applicable emission limit in §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in §60.4320.
- If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.
- The ambient temperature must be greater than 0 °F during the performance test.

[11/6/2014]

3.22 How do I perform the initial performance test if I have chosen to install a NO_X-diluent CEMS?

In accordance with 40 CFR 60.4405, if you elect to install and certify a NO_X-diluent CEMS under §60.4345, then the initial performance test required under §60.8 may be performed in the following alternative manner:

- Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.
- For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.
- Use the test data both to demonstrate compliance with the applicable NO_X emission limit under §60.4320 and to provide the required reference method data for the RATA of the CEMS described under §60.4335.
- Compliance with the applicable emission limit in §60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

[11/6/2014]

3.23 How do I conduct the initial and subsequent performance tests for sulfur?

In accordance with 40 CFR 60.4415(a), (2) and (3) you must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

- For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or
- For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

2) Measure the SO_2 concentration (in parts per million (ppm)), using EPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19-10-1981-Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of EPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using EPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO_2 emission rate:

$$E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P} \quad \text{(Eq. 6)}$$

Where:

E = SO_2 emission rate, in lb/MWh

1.664×10^{-7} = conversion constant, in lb/dscf-ppm

$(SO_2)_c$ = average SO_2 concentration for the run, in ppm

Q_{std} = stack gas volumetric flow rate, in dscf/hr

P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or

3) Measure the SO_2 and diluent gas concentrations, using either EPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19-10-1981-Part 10 (incorporated by reference, see §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use EPA Method 19 in appendix A of this part to calculate the SO_2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the SO_2 emission rate in lb/MWh.

[11/6/2014]

3.24 Combustion Turbine Notification Address

In accordance with 40 CFR 60.7, any notifications or reporting required by the Standards of Performance of New Stationary Sources (NSPS), 40 CFR Part 60, Subpart IIII or Subpart A – General Provisions shall be submitted to the following address:

Air Quality Permit Compliance
Idaho Falls Regional Office
Department of Environmental Quality
900 N. Skyline, Ste. B
Idaho Falls, ID 83402

Phone: (208) 528-2650
Fax: (208) 528-2695

[11/6/2014]

3.25 Incorporation of Federal Requirements by Reference

Unless expressly provided otherwise, any reference in this permit to any document identified in IDAPA 58.01.01.107.03 shall constitute the full incorporation into this permit of that document for the purposes of the reference, including any notes and appendices therein. Documents include, but are not limited to:

- New Source Performance Standards (NSPS), 40 CFR Part 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines

For permit conditions referencing or cited in accordance with any document incorporated by reference (including permit conditions identified as NSPS), should there be any conflict between the requirements of the permit condition and the requirements of the document, the requirements of the document shall govern, including any amendments to that regulation.

[11/6/2014]

40 CFR 72, Subpart A – Acid Rain Program

3.26 Not affected units subject to the requirements of the Acid Rain Program

In accordance with 40 CFR 72.6 (b) the following types of units are not affected units subject to the requirements of the Acid Rain Program:

- For units which commenced construction after November 15, 1990, supplies equal to or less than one-third its potential electrical output capacity or equal to or less than 219,000 MWe-hrs actual electric output on an annual basis to any utility power distribution system for sale (on a gross basis). However, if in any three calendar year period after November 15, 1990, such unit sells to a utility power distribution system an annual average of more than one-third of its potential electrical output capacity and more than 219,000 MWe-hrs actual electric output (on a gross basis), that unit shall be an affected unit, subject to the requirements of the Acid Rain Program.

[11/6/2014]

4 Emergency IC Engines

4.1 Process Description

The emergency IC engines are used to power electrical generators to provide power at the facility in the event of an electrical power interruption.

4.2 Control Device Descriptions

Table 4.1 Emergency IC Engines Description

Emissions Units / Processes	Control Devices	Emission Points
Emergency IC Engine 40084, Central Energy Plant	N/A	Emergency IC Engine No. 40084 stack
Emergency IC Engine 40085, Central Energy Plant	N/A	Emergency IC Engine No. 40085 stack
Emergency IC Engine 40002, Kimball Building	N/A	Emergency IC Engine No. 40002 stack
Emergency IC Engine 40077, Hart Building	N/A	Emergency IC Engine No. 40077 stack
Emergency IC Engine 40082, Manwaring Center	N/A	Emergency IC Engine No. 40082 stack
Emergency IC Engine 40083, Chiller Plant/BCTR/Manwaring Student Center/Facilities	N/A	Emergency IC Engine No. 40083 stack
Emergency IC Engine 40010, Kirkham Building and Spori Building	N/A	Emergency IC Engine No. 40010 stack
Emergency IC Engine 40080, Auxiliary Services	N/A	Emergency IC Engine No. 40080 stack
Emergency IC Engine 40016, Snow Performing Arts Center	N/A	Emergency IC Engine No. 40016 stack
Emergency IC Engine 40015, Clarke Building	N/A	Emergency IC Engine No. 40015 stack
Emergency IC Engine 40009, Radio/Graphic Services Building	N/A	Emergency IC Engine No. 40009 stack
Emergency IC Engine 40012, Ricks Building	N/A	Emergency IC Engine No. 40012 stack
Emergency IC Engine 40008, Radio Tower	N/A	Emergency IC Engine No. 40008 stack
Emergency IC Engine 40011, Substation	N/A	Emergency IC Engine No. 40011 stack
Emergency IC Engine 40018, Menan Butte Radio Tower	N/A	Emergency IC Engine No. 40018 stack
Portable Emergency IC Engine	N/A	Portable Emergency IC Engine stack

[10/2/2019]

Emission Limits

4.3 Opacity Limit

Emissions from the emergency IC engine stacks, or any other stack, vent, or functionally equivalent opening associated with the emergency IC engines, shall not exceed 20% opacity for a period or periods aggregating more than three minutes in any 60-minute period as required by IDAPA 58.01.01.625. Opacity shall be determined by the procedures contained in IDAPA 58.01.01.625.

4.4 Grain Loading

The permittee shall not discharge to the atmosphere from any fuel-burning equipment PM in excess of 0.015 grains per dry standard cubic foot (gr/dscf) of effluent gas corrected to 3% oxygen by volume for gaseous fuels and 0.050 gr/dscf of effluent gas corrected to 3% oxygen by volume for liquid fuels.

Operating Requirements

4.5 Emergency IC Engines Fuel Use

The Emergency IC Engines shall combust ULSD fuel.

[11/6/2014]

Fuel Specifications

4.6 ULSD Fuel Specifications

ULSD fuel oil is fuel which meets ASTM Grades 1 or 2, or a mixture of ASTM Grades 1 and 2, and which has a maximum sulfur content of 0.0015% (15 ppm) by weight.

[11/6/2014]

Monitoring and Recordkeeping Requirements

4.7 Fuel Specifications Recordkeeping

On an as-received basis for each shipment of distillate fuel oil for the emergency IC engines, the permittee shall maintain the following supplier verified and certified information:

- Percent sulfur content by weight

[11/6/2014]

40 CFR 60, Subpart IIII Requirements – Applicable to the 40084 Central Energy Plant and 40085 Central Energy Plant Emergency IC engines

4.8 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

In accordance with 40 CFR 60.4205 (b), the 40084 Central Energy Plant and 40085 Central Energy Plant emergency IC engines shall be EPA Tier II Certified engines.

[11/6/2014]

4.9 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

In accordance with 40 CFR 60.4206, owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 over the entire life of the engine.

[11/6/2014]

4.10 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

In accordance with 40 CFR 60.4211 (f), if you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

There is no time limit on the use of emergency stationary ICE in emergency situations.

You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

- Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.
- Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.
- Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

- The engine is dispatched by the local balancing authority or local transmission and distribution system operator;
- The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.
- The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.
- The power is provided only to the facility itself or to support the local transmission and distribution system.

- The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[11/6/2014]

4.11 Incorporation of Federal Requirements by Reference

Unless expressly provided otherwise, any reference in this permit to any document identified in IDAPA 58.01.01.107.03 shall constitute the full incorporation into this permit of that document for the purposes of the reference, including any notes and appendices therein. Documents include, but are not limited to:

- New Source Performance Standards (NSPS), 40 CFR Part 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

For permit conditions referencing or cited in accordance with any document incorporated by reference (including permit conditions identified as NSPS), should there be any conflict between the requirements of the permit condition and the requirements of the document, the requirements of the document shall govern, including any amendments to that regulation.

[11/6/2014]

40 CFR 63, Subpart ZZZZ Requirements - Applicable to the 40002 Kimball Building, 40077 Hart Building, 40082 Manwaring Building, 40083 Chiller Plant/BCTR/Manwaring Student Center/Facilities Building, 40010 Kirkham Building and Spori Building, 40080 Auxiliary Services Building, 40016 Snow Performing Arts Building, 40015 Clarke Building, 40009 Radio/Graphic Services Building, 40012 Ricks Building, 40008 Radio Tower Building, 40011 Substation, 40018 Menan Butte Radio Tower, and the Portable Emergency IC Engines

4.12 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

In accordance with 40 CFR 63.6640(f), (1) thru (4), if you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

There is no time limit on the use of emergency stationary RICE in emergency situations.

You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

- Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.
- Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.
- Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

[11/6/2014]

4.13 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

In accordance with 40 CFR 63.6640 (f), emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

- The engine is dispatched by the local balancing authority or local transmission and distribution system operator.
- The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

- The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.
- The power is provided only to the facility itself or to support the local transmission and distribution system.
- The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[11/6/2014]

4.14 Incorporation of Federal Requirements by Reference

Unless expressly provided otherwise, any reference in this permit to any document identified in IDAPA 58.01.01.107.03 shall constitute the full incorporation into this permit of that document for the purposes of the reference, including any notes and appendices therein. Documents include, but are not limited to:

- National Emissions Standards for Hazardous Air Pollutants (NESHAP), 40 CFR Part 63, Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

For permit conditions referencing or cited in accordance with any document incorporated by reference (including permit conditions identified as NESHAP), should there be any conflict between the requirements of the permit condition and the requirements of the document, the requirements of the document shall govern, including any amendments to that regulation.

[11/6/2014]

5 Coating Operations

5.1 Process Description

Coating operations are performed at the Physical Facilities #1 Spray Booth, the Physical Facilities #2 Spray Booth, and the Austin Spray Booth at BYU–Idaho as part of facility maintenance as defined in 40 CFR 63.11180.

5.2 Control Device Descriptions

Table 5.1 Coating Operations Description

Emissions Units / Processes	Control Devices	Emission Points
Physical Facilities #1 Spray Booth	Pre-filter and filter system Airless spray gun	Physical Facilities #1 Spray Booth exhaust stack
Physical Facilities #2 Spray Booth	Pre-filter and filter system Airless spray gun	Physical Facilities #2 Spray Booth exhaust stack
Austin Spray Booth	Pre-filter and filter system HVLP spray gun	Austin Spray Booth exhaust stack

Emission Limits

5.3 Emission Limits

The emissions from the Physical Facilities #2 Spray Booth and the Austin Spray Booth stack shall not exceed any corresponding emissions rate limits listed in Table 5.2.

Table 5.2 Coating Operations Emission Limits [(a)]

Source Description	VOC
	T/yr [(c)]
Physical Facilities #1 Spray Booth	N/A
Physical Facilities #2 Spray Booth	0.66
Austin Spray Booth	0.27

a) In absence of any other credible evidence, compliance is ensured by complying with permit operating, monitoring, and record keeping requirements.
b) Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference test method, continuous emission monitoring system (CEMS) data, or DEQ-approved alternative.
c) Tons per any consecutive 12-calendar month period.

5.4 Opacity Limit

Emissions from the Physical Facilities #1 Spray Booth, the Physical Facilities #2 Spray Booth, and the Austin Spray Booth stack stack, or any other stack, vent, or functionally equivalent opening associated with the Physical Facilities #1 Spray Booth, the Physical Facilities #2 Spray Booth, and the Austin Spray Booth stack, shall not exceed 20% opacity for a period or periods aggregating more than three minutes in any 60-minute period as required by IDAPA 58.01.01.625. Opacity shall be determined by the procedures contained in IDAPA 58.01.01.625.

Operating Requirements

5.5 Coating Material Usage Rates

Coating material usage rates at the facility shall not exceed the following limits:

- 500 gal/yr of Duracat-v vinyl lacquer semi-gloss used in the Physical Facilities #2 Spray Booth
- 300 gal/yr of Duracat-v vinyl lacquer semi-gloss used in the Austin Spray Booth

Monitoring and Recordkeeping Requirements

5.6 Coating Material Use Rates

The permittee shall collect and maintain records of the following information to demonstrate compliance with the Coating Material Usage Rates permit condition. The permittee shall perform the required calculations on a monthly basis, using data from the previous 12 consecutive months of operation.

- The name and volume of each coating material used, in gallons per month.
- The total of all coating materials used, in gallons per consecutive 12 calendar month period. The total shall be calculated as a rolling 12 calendar month usage rate, and determined on a monthly basis.
- For each product used in a coating material, the permittee shall collect and maintain a current copy of the information provided by materials suppliers or manufacturers, such as manufacturer's formulation data or MSDS. This shall include, but not be limited to:
    - The manufacturer name and product number.
    - The mass fraction of each toxic air pollutant (TAP), in percent by weight.
    - The mass fraction of each hazardous air pollutant (HAP), in percent by weight.
    - The mass fraction of volatile organic compounds (VOC), in percent by weight.
    - The density, in pounds per gallon.
    - The mass fraction of solids, in percent by weight.

40 CFR 63, Subpart HHHHHH Requirements

5.7 40 CFR 63, Subpart HHHHHH – MACT Standards and Management Practices for Paint Stripping and Miscellaneous Surface Coating Operations, General Compliance Requirements

In accordance with 40 CFR 63.11170 and 63.11180, the facility shall only performance coating operations for facility maintenance.

Facility maintenance means, for the purposes of this subpart, surface coating performed as part of the routine repair or renovation of the tools, equipment, machinery, and structures that comprise the infrastructure of the affected facility and that are necessary for the facility to function in its intended capacity. Facility maintenance also includes surface coating associated with the installation of new equipment or structures, and the application of any surface coating as part of janitorial activities. Facility maintenance includes the application of coatings to stationary structures or their appurtenances at the site of installation, to portable buildings at the site of installation, to pavements, or to curbs. Facility maintenance also includes the refinishing of mobile equipment in the field or at the site where they are used in service and at which they are intended to remain indefinitely after refinishing. Such mobile equipment includes, but is not limited to, farm equipment and mining equipment for which it is not practical or feasible to move to a dedicated mobile equipment refinishing facility. Such mobile equipment also includes items, such as fork trucks, that are used in a manufacturing facility and which are refinished in that same facility. Facility maintenance does not include surface coating of motor vehicles, mobile equipment, or items that routinely leave and return to the facility, such as delivery trucks, rental equipment, or containers used to transport, deliver, distribute, or dispense commercial products to customers, such as compressed gas canisters.

[11/6/2014]

5.8 Incorporation of Federal Requirements by Reference

Unless expressly provided otherwise, any reference in this permit to any document identified in IDAPA 58.01.01.107.03 shall constitute the full incorporation into this permit of that document for the purposes of the reference, including any notes and appendices therein. Documents include, but are not limited to:

- National Emission Standards for Hazardous Air Pollutants (NESHAP) Area Sources, 40 CFR Part 63, Subpart HHHHHH.

For permit conditions referencing or cited in accordance with any document incorporated by reference (including permit conditions identified as NESHAP), should there be any conflict between the requirements of the permit condition and the requirements of the document, the requirements of the document shall govern, including any amendments to that regulation.

[11/6/2014]

6 General Provisions

General Compliance

6.1 The permittee has a continuing duty to comply with all terms and conditions of this permit. All emissions authorized herein shall be consistent with the terms and conditions of this permit and the "Rules for the Control of Air Pollution in Idaho." The emissions of any pollutant in excess of the limitations specified herein, or noncompliance with any other condition or limitation contained in this permit, shall constitute a violation of this permit, the "Rules for the Control of Air Pollution in Idaho," and the Environmental Protection and Health Act (Idaho Code §39-101, et seq).

[Idaho Code §39-101, et seq.]

6.2 The permittee shall at all times (except as provided in the "Rules for the Control of Air Pollution in Idaho") maintain in good working order and operate as efficiently as practicable all treatment or control facilities or systems installed or used to achieve compliance with the terms and conditions of this permit and other applicable Idaho laws for the control of air pollution.

[IDAPA 58.01.01.211, 5/1/94]

6.3 Nothing in this permit is intended to relieve or exempt the permittee from the responsibility to comply with all applicable local, state, or federal statutes, rules, and regulations.

[IDAPA 58.01.01.212.01, 5/1/94]

Inspection and Entry

6.4 Upon presentation of credentials, the permittee shall allow DEQ or an authorized representative of DEQ to do the following:

- Enter upon the permittee's premises where an emissions source is located, emissions-related activity is conducted, or where records are kept under conditions of this permit;
- Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;
- Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
- As authorized by the Idaho Environmental Protection and Health Act, sample or monitor, at reasonable times, substances or parameters for the purpose of determining or ensuring compliance with this permit or applicable requirements.

[Idaho Code §39-108]

Construction and Operation Notification

6.5 This permit shall expire if construction has not begun within two years of its issue date, or if construction is suspended for one year.

[IDAPA 58.01.01.211.02, 5/1/94]

6.6 The permittee shall furnish DEQ written notifications as follows:

- A notification of the date of initiation of construction, within five working days after occurrence; except in the case where pre-permit construction approval has been granted then notification shall be made within five working days after occurrence or within five working days after permit issuance whichever is later;
- A notification of the date of any suspension of construction, if such suspension lasts for one year or more; and

- A notification of the initial date of achieving the maximum production rate, within five working days after occurrence - production rate and date.

[IDAPA 58.01.01.211.01, 5/1/94]

- A notification of the anticipated date of initial start-up of the stationary source or facility not more than sixty days or less than thirty days prior to such date; and
- A notification of the actual date of initial start-up of the stationary source or facility within fifteen days after such date.

[IDAPA 58.01.01.211.03, 5/1/94]

Performance Testing

6.7 If performance testing (air emissions source test) is required by this permit, the permittee shall provide notice of intent to test to DEQ at least 15 days prior to the scheduled test date or shorter time period as approved by DEQ. DEQ may, at its option, have an observer present at any emissions tests conducted on a source. DEQ requests that such testing not be performed on weekends or state holidays.

6.8 All performance testing shall be conducted in accordance with the procedures in IDAPA 58.01.01.157. Without prior DEQ approval, any alternative testing is conducted solely at the permittee's risk. If the permittee fails to obtain prior written approval by DEQ for any testing deviations, DEQ may determine that the testing does not satisfy the testing requirements. Therefore, at least 30 days prior to conducting any performance test, the permittee is encouraged to submit a performance test protocol to DEQ for approval. The written protocol shall include a description of the test method(s) to be used, an explanation of any or unusual circumstances regarding the proposed test, and the proposed test schedule for conducting and reporting the test.

6.9 Within 60 days following the date in which a performance test required by this permit is concluded, the permittee shall submit to DEQ a performance test report. The report shall include a description of the process, identification of the test method(s) used, equipment used, all process operating data collected during the test period, and test results, as well as raw test data and associated documentation, including any approved test protocol.

[IDAPA 58.01.01.157, 4/5/00 and 4/11/15]

Monitoring and Recordkeeping

6.10 The permittee shall maintain sufficient records to ensure compliance with all of the terms and conditions of this permit. Monitoring records shall include, but not be limited to, the following: (a) the date, place, and times of sampling or measurements; (b) the date analyses were performed; (c) the company or entity that performed the analyses; (d) the analytical techniques or methods used; (e) the results of such analyses; and (f) the operating conditions existing at the time of sampling or measurement. All monitoring records and support information shall be retained for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Supporting information includes, but is not limited to, all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. All records required to be maintained by this permit shall be made available in either hard copy or electronic format to DEQ representatives upon request.

[IDAPA 58.01.01.211, 5/1/94]

Excess Emissions

6.11 The permittee shall comply with the procedures and requirements of IDAPA 58.01.01.130–136 for excess emissions due to start-up, shut-down, scheduled maintenance, safety measures, upsets, and breakdowns.

[IDAPA 58.01.01.130–136, 4/5/00]

Certification

6.12 All documents submitted to DEQ—including, but not limited to, records, monitoring data, supporting information, requests for confidential treatment, testing reports, or compliance certification—shall contain a certification by a responsible official. The certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document(s) are true, accurate, and complete.

[IDAPA 58.01.01.123, 5/1/94]

False Statements

6.13 No person shall knowingly make any false statement, representation, or certification in any form, notice, or report required under this permit or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.125, 3/23/98]

Tampering

6.14 No person shall knowingly render inaccurate any monitoring device or method required under this permit or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.126, 3/23/98]

Transferability

6.15 This permit is transferable in accordance with procedures listed in IDAPA 58.01.01.209.06.

[IDAPA 58.01.01.209.06, 4/11/06]

Severability

6.16 The provisions of this permit are severable, and if any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

[IDAPA 58.01.01.211, 5/1/94]